

**Department of Energy**  
Bonneville Power Administration  
P.O. Box 3621  
Portland, Oregon 97208-3621  
September 30, 1997

EXECUTIVE OFFICE

In reply refer to: AR

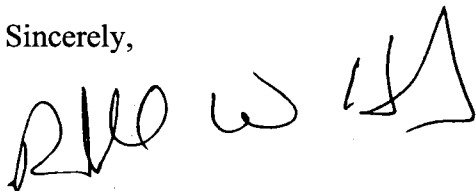
The Honorable John D. Dingell  
Ranking Member  
Commerce Committee Democratic Office  
U.S. House of Representatives  
Washington, DC 20515

Dear Congressman Dingell:

Thank you for your letter of April 10, 1997, to the Bonneville Power Administration (Bonneville). In your letter, you stated that the Commerce Committee is examining the question of whether Congress should enact legislation concerning the electricity industry and requested Bonneville's response to your specific questions concerning the industry.

Enclosed is our response to your specific questions. We trust that the information provided will assist in providing a better understanding of the important issues involved in restructuring the electric power industry. Please contact us if we can provide further information.

Sincerely,

A handwritten signature in black ink, appearing to read 'R. Hardy', followed by a stylized flourish.

Randall W. Hardy  
Administrator and Chief Executive Officer

Enclosure

Questions From the April 10, 1997 Letter  
Regarding Legislation in the Electricity Industry

**Question 1:** How has increased competition in wholesale electricity markets affected your business? To what extent has the Bonneville Power Administration benefited and to what extent have you been disadvantaged?

**Answer 1:** Competition has affected our business dramatically. In particular, the Federal Energy Regulatory Commission's requirements for mandate for wholesale open transmission access (based in part on authorities granted by the Congress in the Energy Policy Act of 1992) significantly affected the competitive landscape for the Bonneville Power Administration (Bonneville), since most of our sales are at wholesale. Though Bonneville sells almost one-third of its requirements power directly to its direct service industry (DSI) customers, these companies had the right to terminate their Bonneville power sales contracts on one year's notice and switch to their local utility. The local utility then potentially could have accessed the market to obtain power for the DSI load. This contractual landscape, coupled with low West Coast gas prices and excess generating capacity in California (which led to West Coast energy prices below Bonneville's prices), necessitated that Bonneville undertake significant and difficult actions in 1995 and 1996 to react to the newly competitive market.

In 1995 Bonneville had significant financial exposure to potential loss of a large portion of its existing customer and revenue base. Even though we had load under contract until 2001, we were faced with the prospect of taking a very hard line with customers about contract enforcement with an uncertain outcome. Alternatively, Bonneville could have taken actions to respond to the market and customer needs in order to foster better relations than would be the case with the contract enforcement litigation approach. As a result of the decision to foster more effective business relations, we renegotiated most of our contracts with our DSI and public power customers (representing approximately 75 percent of Bonneville's revenues) to allow customers some guaranteed amount of supply diversification, and assured them fixed prices for Bonneville power through the remainder of the contract term (ending 9/30/2001).

Responding to the competitive wholesale market, we cut planned budgets by over \$600 million annually including reductions in important and sensitive programs such as energy conservation. We canceled all resource acquisitions and terminated two mothballed nuclear plants. We reduced staff and contractors by over 1000, and are in the process of cutting another 1000 from a level of approximately 5000. Agreement was achieved on a fish budget which creates funding stability for recovery efforts of endangered salmon. As a result of these efforts, we were able to reduce our power rates by 15 percent.

Along with retaining a major portion of the load we had under contract, we also began to market excess Federal power to some new customers, such as New Energy Ventures and the Bay Area Rapid Transit District in Northern California. Making sales to new customers is important to ensuring the United States Treasury (Treasury) investment is protected. Since Bonneville anticipates that some additional portion of its existing customer base will choose to diversify its supply portfolio, it will be important for Bonneville to be in a position to sell surplus Federal power at firm prices to avoid revenue loss from selling into the alternative, lower-priced, spot market.

Of course, the real test still lies a head. As you know, we are facing the prospect of most of our power sales contracts expiring on 9/30/2001. The potential for retail access by that time appears high. The recently completed Comprehensive Review of the Northwest Energy System (Comprehensive Review) by the four Northwest Governors contained numerous recommendations pertaining to the role of Bonneville as an energy supplier in this new regulatory regime. One of the Comprehensive Review's recommendations was for Bonneville to initiate a "Subscription Process" for selling Bonneville power at cost-based rates for the period starting after current long-term contracts expire in 2001. The Review also recommends that to the extent regional entities do not in the future either purchase power on a long-term basis or pay option fees, BPA should be free to charge a market price for its power resources. How a move to greater wholesale competition ultimately affects Bonneville will in large part depend on the results of this process.

**Question 2:** What plans does BPA have for responding to the challenges posed by increased competition in the electric industry, including the possibility of retail competition? Have any states in your region adopted or are they considering retail competition plans? How might state action affect your business?

**Answer 2:** Bonneville is taking action in three areas to prepare for retail access. Bonneville is: (1) cutting costs in order to make its rates more competitive, (2) preparing to sell to new regional and extra-regional markets in preparation for the loss of existing customers, and (3) preparing the transmission business to accommodate the move to retail access.

In response to changing electric energy markets and unprecedented competition, Bonneville began its Competitiveness Project in 1993, which created a market and customer focus and a greater emphasis on cost management. In its 1995 Business Plan, Bonneville stated its intent to transform itself from a traditional bureaucracy into a streamlined, efficient, market-driven Federal enterprise. This effort has resulted in cutting over \$600 million in annual cost from projected Bonneville budgets and resulted in a 15 percent rate decrease to meet the market in 1996.

Bonneville expects to lose some of its existing load as retail access provides alternatives for consumers of existing customers. Based on the Comprehensive Review recommendations, Bonneville expects to market the abandoned power thus made available to: (1) residential customers of investor owned utilities (IOU), (2) other Pacific Northwest loads, and (3) extra-regional loads. Bonneville does not anticipate selling beyond its current retail level, but rather will sell at wholesale to entities such as aggregators.

In response to declining Federal loads, Congress, through the 1996 Energy and Water Appropriations Act, changed Bonneville's authority to market a certain category of surplus Federal power outside the Pacific Northwest. These changes include provisions allowing Bonneville to: (1) sell excess Federal power outside the Pacific Northwest for up to 7 years, eliminating the 60-day energy call back and the 5-year capacity call back provision of the Regional Preference Act, and (2) allow excess firm power to be resold (eliminating the limitation on resale in the Bonneville Project Act of 1937). Bonneville must first offer available excess Federal power to customers within the Northwest. Sales of excess Federal power help sustain Bonneville's revenues, and therefore help Bonneville pay its costs, while keeping its firm power rates competitive, and supporting public benefits in the region. Maintaining this authority, as was also alluded to in answer to question 1, is important to sustaining these public benefit results.

Bonneville is operating its Transmission and Power business lines in a manner consistent to the maximum extent possible under law with the Federal Energy Regulatory Commission's (FERC) mandated functional unbundling of the electricity industry. Bonneville has established open access transmission tariffs, is buying transmission for its own use under those tariffs, has established an Open Access Same Time Information System (OASIS), and has filed procedures with FERC implementing its standards of conduct.

The final report of the Comprehensive Review recommends legislative separation of Bonneville's two primary business systems, Transmission and Power Marketing, into two separate legal entities. Legal separation would require legislation. Several financial aspects of Bonneville's current "one-agency, administratively separated" business structure could be affected by legislative separation. The extent to which Bonneville's future financial status would be impacted could only be determined by review of how proposed legislation would address such issues as the Bonneville Fund, Treasury borrowing authority, etc. One of the Comprehensive Review's stated goals is to ensure repayment of the debt to the Treasury with equal or greater probability than currently exists, while not compromising its security or the tax-exempt status of \$6.7 billion of outstanding nuclear construction bonds.

Turning to state activities, Bonneville plans to support states in their efforts to provide for consumer choice. However, Bonneville must be assured that it can

continue to recover sufficient revenues to meet its costs and repay the Federal investment in the Federal Columbia River Power System (FCRPS). Therefore, Bonneville will evaluate state legislation to determine whether it has provided protection through 2001 for Bonneville's wholesale power sales contracts with local utilities or other means by which Bonneville can recover the revenues expected under the contracts. If such legislation provides for protection of Bonneville's expected revenue under existing contracts, or provides for stranded cost recovery for Bonneville, Bonneville will be able to support the state initiatives consistent with its obligation to ensure Treasury repayment. Bonneville has also advocated that state legislation ensure Washington Public Power Supply System (WPPSS) net billing participants can continue to meet their contractual obligations to WPPSS. State legislation should also not frustrate Bonneville's ability to recover stranded investment after September 30, 2001, if necessary.

Several states in the region are considering legislation addressing retail wheeling. The state of Montana has enacted retail access legislation while Washington and Idaho have deferred legislation for this session. Legislation in Oregon is still pending. We have been concerned about the impact of state legislation on: (1) Bonneville's ability to collect stranded cost and (2) Bonneville's ability to sell to new market contracts established under state law. These concerns have been expressed to key state legislators in all four states. The Montana legislation does not appear to create problems in those areas. Bonneville is supporting IOU retail wheeling pilot programs that have been proposed or already are in effect within the region by providing transmission services under existing open access rates, tariffs and scheduling practices. Bonneville also will provide transmission services for retail transactions involving publicly-owned utilities, in accordance with the terms and conditions of their existing power sales contracts with Bonneville. Some of Bonneville's publicly-owned utility customers have the right to diversify their purchases--that is, to purchase a certain amount of non-Federal power. Bonneville will support retail wheeling programs of such utilities up to the level of each utility's unutilized diversification rights.

Bonneville is concerned that the potential reliability impacts of retail wheeling be understood and addressed. The WSCC defines the rules under which all transmission providers in the region operate. However, the existing WSCC practices were designed before the advent of open access, which has greatly increased the number of transactions. For example, in the past two years Bonneville has seen the number of daily wholesale transactions increase from about 500 to 2000 accounts. Retail open access could drive the number of accounts to hundreds of thousands or even higher. Bonneville can not track that many transactions. Local distribution companies, or load aggregators must take on this responsibility, if wholesale transmission providers like Bonneville are to maintain adequate levels of system reliability. System dispatchers must have good information on all schedules through their system in order to be able to respond

quickly and effectively to system emergencies. Therefore, the rules and standards for scheduling retail wheeling transactions must be defined.

**Question 3:** Do you believe Congress needs to modify the federal authorities applying to BPA? If so, please explain why and how.

**Answer 3:** The restructuring of the electric industry raises many issues for Bonneville with regard to both power sales and transmission services. A recent region-wide effort initiated by Bonneville and the Department of Energy (DOE) and sponsored by the region's governors assessed the need for changes to Bonneville's statutes. This effort, called the Comprehensive Review, concluded that it was important for Bonneville to be separated legislatively into a generation marketing entity and a transmission services entity in order to eliminate any perceptions of favored treatment of Bonneville's power marketing function by the transmission function. The Comprehensive Review also recommended that Bonneville participate in a regional Independent Grid Operator (IGO), either as the IGO itself or as a participating member. The Comprehensive Review also proposed a process for allocating Bonneville power in the post-2001 period which allows for the maintenance of cost based rates, public and regional preference so long as the power is subscribed through a new round of firm power contracts. To the extent Bonneville power is not subscribed, it would be sold at market price. Currently, the Administration is reviewing the Comprehensive Review recommendations. Except for endorsing stranded cost recovery legislation, the Administration has taken no position on whether legislation is needed to modify Bonneville's authorities. Bonneville needs and the Administration supports a contingent stranded cost recovery mechanism, to help avoid burdening the United States taxpayers, who under law stand last in the line of Bonneville creditors. The mechanism must be fair and must not ease pressure for containment of costs. The Administration supports statutory changes which create a more robust contingent stranded cost recovery mechanism for Bonneville.

Recommendations for implementing the Comprehensive Review's conclusions are being developed by the Northwest Governors' Transition Board. A Transition Board working group is developing a list of issues which must be addressed legislatively if Bonneville is to be separated into generation and transmission entities. This process is scheduled to be completed by early June.

**Question 4:** The Bonneville Power Administration currently pays all of the costs associated with Washington Public Power Supply System (WPPSS) reactors WNP1, WNP2 and WNP3. Only WNP2 was completed. If the market price for electricity is lower than BPA's cost of producing power in 2001 when most of its current power sales contracts expire, BPA could have a significant stranded cost problem. If this occurs, who should pay such costs - the federal Treasury, WPPSS bondholders, or Northwest entities on whose behalf BPA incurred its WPPSS obligations? What mechanism should be used to address such stranded costs?

**Answer 4:** Stranded costs are a subset of a more general issue of cost recovery. We have faced revenue variability in the past, and we will continue to face variability in our revenues. Most years, our revenues will exceed our costs, but in some years our revenues may fall below our costs. In the event that we do not recover all our costs in a particular year, it is not necessarily attributable to any given type of cost, such as fish and wildlife costs, WPPSS costs, other generation costs, or conservation costs. Bonneville has generally approached stranded costs consistent with FERC's so-called "revenues lost" approach, but, instead of using FERC's method of linking lost revenues to individual customers, Bonneville likely would calculate overall lost revenues. See 61 Fed. Reg. 21,540, 21,654 (1996). FERC expressly eschewed calculating and allocating stranded costs in terms of a cost-of-service approach, avoiding an asset-by-asset review. Nevertheless, because Bonneville may repay the Treasury only after first meeting its other costs, any cost underrecovery faced by Bonneville--whatever its source--ultimately would redound to the detriment of the Treasury. In such a situation, Bonneville would temporarily defer payments to the Treasury and then refinance those missed payments at current Treasury interest rates until they were paid. See Transmission System Act, 16 U.S.C. §838k(b); Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 832e(a)(2)(A).

While our loads are at risk as a result of a move to open access transmission and contract expiration, the most likely scenario is that West Coast power market prices will recover and Federal power at cost, assuming no substantial cost increases, will be an economically very attractive product. Putnam Hayes and Bartlett Inc. (PH&B) examined this issue and released a report in February 1996 which indicated that Bonneville in the most likely scenarios would not face stranded costs. However, if market prices were "low" (for example PH&B estimated 16.5 mills per kWh for power in 1996 dollars in 2002) and or Bonneville costs rose above those of the current rate period, PHB estimated these costs (for the 2002 to 2012) could amount to \$0.6 billion based on their market and BPA cost forecasts.

Two factors can cause Bonneville to not generate enough revenue to cover costs: (a) market prices remain low, and/or (b) we are not able to control costs in order to keep our prices at or below market. Each is discussed below.

With respect to market prices, using a range of forecasts, we presently estimate market prices being between about 1.7 and 3.9 cents/kWh during the 2001-2007 period (1996 dollars). Under the low market price forecast, we estimate prices to range between 1.7 and 2.3 cents/kWh over the 2001 to 2007 period (1996 dollars). Under the high price forecast, the range is from about 2.7 cents/kWh to about 3.9 cents/kWh (1996 dollars). We are fairly confident about these estimates considering that (a) the West Coast economy is continuing to improve; (b) West Coast gas prices are increasing; and (c) given the price differential between East Coast and West Coast gas (East Coast higher), as new pipeline capacity is

completed, more West Coast gas will begin to move East which will place further upward pressure on West Coast gas prices. We recognize that forecasts can be wrong and that there are some scenarios under which West Coast energy prices will stay below 2 cents/kWh. It is in these scenarios where Bonneville's ability to earn sufficient revenues to cover costs will be most seriously challenged, and it is these cases under which PH&B estimated cost underrecovery in the nearer term.

Concerning Bonneville's rate, our rate for delivered energy is about 2.2 cents/kWh for the current rate period ending 9/30/2001. This represents a 15 percent reduction from 1995. At this time, Bonneville does not have projected rates for the period from 10/1/2001 through 2007. We have established a goal that, when the current contracts expire, our costs will be fully recoverable if we are selling into a 2 cent market. There are several reasons to avoid interpreting this cost level as a rate. These reasons are: (1) product design and market forces will tend to drive our rate design decisions in the next rate period and our average rate during the next period cannot be estimated at this time; (2) the subscription process is underway and will define what customers want in terms of product design and pricing; and, (3) translating costs into rates requires a number of steps reflecting the load characteristics of specific customers or groups of customers. Nevertheless, this goal, if met, should assure that the PH&B "stranded" scenario remains only a very remote possibility. In addition to the cost management actions described in the answer to question 1, BPA intends to implement additional cost reductions.

On the revenue side, a successful subscription process that concludes with customers entering into contracts would do a great deal to ensure Bonneville cost recovery, and minimize the need for a separate cost recovery mechanism.

In the unlikely event that we underrecover our power revenues, we believe we do have the authority to use the transmission system to generate additional revenues to recover power costs. A strong argument exists that the Administrator has the authority, when necessary to meet the Administration's statutory obligation to recover costs and repay the Treasury, to allocate to transmission rates generation costs that otherwise cannot be recovered through power rates. This position is supported by Bonneville's organic statutes, and cases interpreting those statutes. Bonneville expects, however, that if customers were to face a stranded cost charge, they would challenge this position in court. While Bonneville believes it would ultimately prevail in any such litigation, it cannot predict how a court would rule. The response that follows is not intended to be an exhaustive treatment of the Administrator's authority to recover stranded generation costs through transmission rates, but rather an overview highlighting the basis for that authority.

Section 7(a)(1) of the Northwest Power Act, 16 U.S.C. § 839 et seq., provides, in pertinent part, that Bonneville's rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power

shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law. 16 U.S.C. § 839e(a)(1).

Similarly, section 7(a)(2) of the Northwest Power Act provides that FERC shall review Bonneville's wholesale power and transmission rates to ensure that they are "sufficient to assure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting the Administrator's other costs" and are "based upon the Administrator's total system costs." 16 U.S.C. § 839e(a)(2)(A)-(B).

Section 7 also contains detailed rate directives describing how rates for individual customer groups are to be derived--statutory cost entitlements and allocations, not cost causation, are the operative themes of these statutory directives. *Id.* § 839(e); see also The Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838g-h (Transmission System Act); Flood Control Act of 1944, 16 U.S.C. § 825s. Congress intended, however, that these Bonneville rate directives be "[s]ubject to the general requirements (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total cost, . . ." H.R. Rep. No. 96-976, 96th Cong., 2nd Sess., pt. 2, at 36 (1980)(emphasis added). Numerous other statutory rate setting standards are applicable to Bonneville's power and transmission rates. See, e.g., Transmission System Act, 16 U.S.C. § 838g-h; Flood Control Act of 1944, 16 U.S.C. § 825s.

Congress' expectation that Bonneville would continue to set its rates so that its total revenues continue to recover its total cost harkens back to the Transmission System Act, 16 U.S.C. § 838. While Congress, in passing the Transmission System Act, contemplated that the transmission and power functions each would ordinarily pay its own way, Congress nevertheless clearly envisioned that Bonneville's entire revenues--power and transmission--would: (1) be available as security for all Bonneville costs; and (2) be available, if necessary, to pay all Bonneville costs. E.g., 16 U.S.C. §§ 838g, 838i, and 838k(b); Bonneville Power Administration Financing, Hearing on S. 3362 before the Subcomm. on Water and Power Resources of the Committee on Interior and Insular Affairs, 93rd Congress, 2d Sess., 95-96 (June 6, 1974) (Statement of C. King Mallory, Acting Assistant Sec., Energy and Minerals, Department of the Interior). Indeed, Mr. Mallory made clear in his statement that

Complete cost recovery has been an overriding principle of the Federal power program in the Pacific Northwest and it will continue to be an

inviolable rule of conduct after enactment of the proposed Federal Columbia River Transmission System Act. *Id.* at 95.

Bonneville, thus, was directed to establish power and transmission rates that produced, in the aggregate, sufficient revenues to pay all Bonneville's costs. Section 9 of the Transmission System Act provides in pertinent part that rates for the sale of power and for the transmission of non-Federal electric power over the Federal transmission system shall be fixed and established having regard to the recovery of the cost of producing and transmitting such electric power, including the amortization of the capital investment allocated to power over a reasonable period of years, and

at levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to this Act, and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith. 16 U.S.C. § 838g; see also 16 U.S.C. § 838i(a)(establishing single Bonneville fund).

All Bonneville revenues are to be placed in the single Bonneville fund, 16 U.S.C. § 838(a), and paid in the priorities directed by section 13 of the Transmission System Act, 16 U.S.C. § 838k(b).

Cost causation has not been the operative principle of either Bonneville ratemaking or its provision of security for debt. When the Transmission Act was enacted there was not the expectation that someday transmission rates and revenues could not be looked to if necessary to cover other than transmission costs, or that power rates and revenues could not be looked to if necessary to cover transmission costs, but the reasonable expectation was to the contrary. See, *Bonneville Power Administration Financing, 1974: Hearings on S. 3362 Before the Subcomm. on Water and Power Resources, 93rd Cong., 2d Sess., 108 (1974)* (testimony of Administrator Hodel that the transmission obligation is a merged obligation of the entire FCRPS and that revenues from one function would be available to pay costs of another function when necessary). The outstanding WPPSS net-billed project and other third-party project debt (approximately \$7.1 billion), and the massive conservation and fish and wildlife Treasury debt (approximately \$629 million and \$80 million respectively) are a system-wide Bonneville undertaking and responsibility.

Customers facing a Bonneville stranded cost charge likely would challenge the Administrator's authority to assess such a charge against them. The precise arguments supporting such a challenge would depend on the nature of the charge developed by Bonneville. In general, however, customers may argue that an allocation of power costs to transmission rates, in particular any costs associated

with fish and wildlife, conservation programs, or the sale or inability to sell excess electric power, may be allocated only to power rates pursuant to section 7(g) of the Northwest Power Act. Section 7(g) provides in pertinent part:

Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this chapter, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife . . . and the sale of or inability to sell excess electric power. 16 U.S.C. § 839e(g).

Transmission customers facing a Bonneville stranded cost charge may be expected to argue that any allocation of power costs to transmission rates violates the directives in the Transmission System Act and the Northwest Power Act that transmission rates be equitably allocated between Federal and non-Federal power utilizing the transmission system. See, Northwest Power Act, § 839e(a)(2)(C); Transmission System Act, § 838h.

In addition, customers seeking transmission from Bonneville through an order from the FERC pursuant to sections 211/212 of the Federal Power Act may argue that any stranded cost charge Bonneville proposes, as part of the rate for such service, violates the just and reasonable standard contained in section 212; or that Bonneville otherwise has not met the tests established by FERC in Orders 888 and 888-A for the recovery of stranded costs. (Note: FERC 888 and 888-A do not apply to non-jurisdictional entities including Bonneville, however FERC may order Bonneville to provide transmission on a case-by-case basis under Section 211 of the Federal Power Act, but under Section 212 (i) of the Federal Power Act such FERC orders must be consistent with Bonneville's existing statutes. See also FERC's discussion of this at pages 825-827 of FERC order 888-A of March 4, 1997).

Finally, using the transmission system to recover costs traditionally allocated to power rates will be limited by practical economic and technical considerations, such as bypass, self-generation, and whether and how Bonneville stranded costs could be recovered through an IGO.

Addressing Bonneville cost recovery in the manner just described would represent a policy judgment that this approach would best assure overall Bonneville cost recovery over time. Further, it represents a judgment that no one cost category should be isolated as "the cause" of cost underrecovery. Were one to attempt to isolate particular costs, equity considerations might well suggest that one attempt to assign those costs to customers that caused or benefited from the undertaking. However, in connection with a system like Bonneville's that was planned on a single, integrated system basis to meet all loads, that path of isolating only particular costs leads to extremely difficult and subjective determinations. For

instance, over the past 16 years one of Bonneville's largest customer segments--and therefore arguably one of the system's primary beneficiaries--has been the IOUs participating in the residential exchange program, so one well might question whether they or their residential exchange customers should be subject to Bonneville's stranded costs. On the other hand the system was built primarily to meet the needs of public utility and DSI customers. In particular WPPSS, which represents one-third of Bonneville's costs is based on contractual agreements entered into by Northwest public utility systems. Consequently, an argument can be made that stranded costs should be borne by such customers.

In conclusion, assuming the most likely market forecast and if Bonneville's costs remain stable, the potential for Bonneville stranded costs is remote. If market prices are low or Bonneville costs rise, however, Bonneville could have a stranded cost problem. Under current law, Bonneville could put stranded costs in rates, but the existing mechanism would be challenged in litigation and may not be considered to be equitable. Consequently, Bonneville needs and the Administration supports a contingent stranded cost recovery mechanism, to help avoid burdening the United states taxpayers, who under law stand last in the line of Bonneville creditors. The mechanism must be fair and must not ease pressure for containment of costs. The Administration supports statutory changes which create a more robust contingent stranded cost recovery mechanism for Bonneville. Bonneville Administrator, Randall Hardy, on June 12, 1997 testified before the House Subcommittee on Water and Power on the future of Bonneville in a competitive electric utility marketplace. That testimony included the Administration's perspectives on some of the key issues the Comprehensive Review considered and presented the Administrations support for statutory changes which create a more robust contingent stranded cost recovery mechanism for Bonneville. That testimony is attached to this response. The testimony follows:

**Question 5a:** Please address the general impact of such legislation. Would legislation authorizing the states to resolve stranded costs issues be beneficial or not, and what if any risks might it pose for the federal taxpayer?

**Answer 5a:** The introduction of retail competition likely would change our existing customer base, particularly in the post-2001 period. At least some of the retail customers of Bonneville's existing customers would move to alternative /suppliers. In order to offset this loss of market, we would either have to find an alternative market for firm power, or sell the surplus power in spot markets for significantly reduced prices, thereby endangering our ability to make our Treasury payments. It is important to assure that as states do institute stranded cost rules that these rules allow retail utilities to collect for wholesale stranded costs and provide any such revenues collected to the stranded wholesale suppliers. It also is important that the legislation preserve the ability of WPPSS participants to meet their net billing obligations, including doing so through the imposition of stranded investment charges via the local distribution system if necessary.

In our case, if state legislation were to require retail open access prior to 2001, such legislation must avoid interference with our contracts and the revenue stream they provide Bonneville through 9/30/2001. Until the expiration of our power sales contracts on this date, we will support state efforts to move to open retail access only if such efforts do not harm the value to us of these contracts. If a state action to move to open retail access does not protect our power revenues, we reserve the option of not providing wheeling and/or imposing transmission surcharges wherever possible and appropriate. In addition, the legislature should act to ensure that aggregators are authorized to market to residential and small farm load; Bonneville then would market to those aggregators thereby ensuring that residential and small farm customers continue to have access to Bonneville's power. For the period after the expiration of Bonneville's current contracts, state legislation should not prevent local utilities from recovering, through their local distribution charges or other means, stranded investment charges that are lawfully imposed at the Federal level.

**Question 5b:** If Congress were to enact legislation mandating retail competition by a date certain, what impact might this have on your activities? If Congress were to enact retail competition legislation, are there any unique circumstances affecting BPA that should be addressed? Should existing statutes be modified as part of any such bill?

**Answer 5b:** First, as noted above, many of our contracts expire on 9/30/2001. Therefore, any Federally mandated retail open access prior to that date might likely create the same revenue underrecovery problem as if such action were taken by a state. Beyond that, the Administration still is considering the proposal made by the four Northwest governors regarding the future of Bonneville and, as yet, is not prepared to make any legislative recommendations for changes to Bonneville.

**Question 6:** To what extent is your transmission system required to operate under the same rules as privately owned utilities? Although you are not required under current law to comply with Order 888 and other similar FERC directives, have you taken any voluntary steps to comply? If so, please explain why.

**Answer 6:** The FERC was granted the authority in the Energy Policy Act of 1992 to order transmitting utilities, including Bonneville, to provide wheeling to eligible customers and to establish the terms of such service. The legislation directs FERC to assure that any orders to Bonneville are consistent with other law applicable to Bonneville. With respect to transmission rates, the statute imposed Federal Power Act rate standards on rates for FERC-ordered transmission while retaining (1) Bonneville's existing transmission rate standards and (2) the procedures for a regional rate case and FERC rate review established in the 1981 Northwest Power Act. Also, pursuant to Order No. 888, in order to obtain transmission service from other transmitting utilities under their open access tariffs, Bonneville must commit to providing reciprocal service to those utilities.

Pursuant to the DOE's comparability policy and Bonneville's own commitments to its customers, Bonneville developed open access transmission tariffs during a nine month formal regional hearing process. A settlement of the terms and conditions was executed by the following parties: (1) Bonneville; (2) 10 of its DSI customers; (3) the British Columbia Power Exchange Corporation (Powerex); (4) six regional investor-owned utilities; and (5) representatives of all but one of Bonneville's publicly-owned and cooperative utility customers. Settlement occurred in March 1996, immediately prior to FERC's release of its Final Rule Tariff, and consequently Bonneville's tariffs differ in some respects from FERC's tariff. Bonneville since has filed its transmission rates and open access tariffs voluntarily with FERC for review and approval.

Bonneville also has separated its transmission business functionally from its power marketing business and developed Standards of Conduct to govern the interactions of these two units. The Standards of Conduct also have been filed voluntarily with FERC for approval.